BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of	)	
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PUBLIC UTILITIES COMMISSION	)	Docket No. 2008-0274
	)	
Instituting a Proceeding to Investigate	)	
Implementing a Decoupling Mechanism	)	
for Hawaiian Electric Company, Inc., and	)	
Hawaii Electric Light Company, Inc., and	)	
Maui Electric Company, Limited.	)	
	)	

HAIKU DESIGN AND ANALYSIS

RESPONSES TO THE NATIONAL REGULATORY RESEARCH INSTITUTE PAPER

APPENDIX 2 QUESTIONS FOR THE PARTIES

WITH ATTACHMENTS 1, 2 AND 3

AND

CERTIFICATE OF SERVICE

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<u>APPENDIX 2 QUESTIONS FOR THE PARTIES</u>

Carl Freedman, dba Haiku Design and Analysis (HDA) respectfully offers the following responses to the *Appendix 2: Questions to the Parties* (Questions) in the National Regulatory Research Institute (NRRI) scoping paper titled *"Decoupling" Utility Profits from Sales: Design Issues and Options for the Hawaii Public Utilities Commission* (Scoping Paper).

HDA notes that the Questions ask for responses that include statements of positions on several of the issues in this docket. HDA offers its responses as preliminary positions for the consideration of the Commission and the parties. HDA will state its final positions in this docket in its briefs.

HDA Responses to Appendix 2: Questions for the Parties

1. **Why do electric utilities need decoupling at this time? Please address decoupling needs created by the utility's rate design and Hawaii's emphasis on electricity strategies that would reduce utility sales. If possible, quantify the need.**

RESPONSE:

Hawaii has established and continues to promote progressive policies to encourage energy efficiency measures and customer sited renewable generation technologies that would (other things being equal) result in decreased levels of energy sales and demand. Existing rate designs implicitly encourage utilities to maintain or increase sales and demand levels (between rate cases) because utility earnings increase with increased sales and demand billing. This is because the utilities' short run marginal costs of generation and capacity are less than marginal rates in most rate classes.[1] Decoupling, if properly implemented, would make the electric utilities ambivalent to changes in levels of sales (and demand if included in the decoupling mechanism) that would occur between rate cases.

1.1. Does the administration of the energy efficiency programs by a third-party administrator affect the need for and potential benefits of decoupling?

RESPONSE:

Yes. Since the energy efficiency programs will henceforth be administered by a third-party administrator one principal reason for decoupling no longer exists. In particular, since the third party administrator is independent of the utilities it would not be concerned with revenue erosion as a disincentive to diligently perform its duties to reduce energy sales.

But... It should be recognized, however, that the assistance and cooperation of the utilities to support the third party administration of the energy efficiency programs remain important. Decoupling would still serve to promote the effective implementation of energy efficiency by making the utilities less indisposed to reductions in sales.

Since the load management and demand response programs will reside with the utilities, decoupling may have a more direct role in addressing revenue erosion associated in reductions in billed demand charges that would result from diligent implementation of these programs.

1.2. Is the need for decoupling the same on each island? Please consider the frequency in curtailments of as-available renewable generation.

RESPONSE:

HDA is not aware of significant differences in the need for decoupling on each island.

The frequency of curtailments of as-available renewable generation is an important consideration but is more directly addressed by other means than by a decoupling mechanism. HDA is not aware of any direct link between decoupling and the issue of frequency of curtailments.

[1] See HDA Attachment 1which shows marginal costs and marginal rates for each HECO customer class.

2. **Please propose a preferred decoupling methodology and in doing so, please answer these questions.**

RESPONSE:

HDA proposes a decoupling methodology (HDA example mechanism) for purposes of discussion and consideration by the Commission and parties in this docket. HDA is not yet certain that this mechanism will ultimately be its "preferred" methodology in this docket. Several aspects of the methods proposed by HECO and the Consumer Advocate were not specified in detail and remain unclear. HDA hopes to learn more about these proposals in the upcoming informal technical workshop.

The HDA example mechanism proposed here is patterned after and is essentially identical to the mechanism designed by HDA for Rocky Mountain Institute (RMI) and proposed to the Commission in the Energy Efficiency Docket No. 05-0069 (Energy Efficiency Docket). An explanation and detailed working example of the HDA example mechanism is provided in HDA Attachment 2. This attachment is a reprint of an RMI filing in the Energy Efficiency Docket.[2]

HDA offers an alternative decoupling mechanism proposal for the following reasons:

(a) HDA wants at least one decoupling mechanism to be considered in this proceeding that is simple enough and certainly feasible to implement. The HECO and Consumer Advocate proposals are complicated approaches that would require substantial administrative overhead for the utilities, the Consumer Advocate and the Commission, and may present excessive opportunities and incentives for gaming in application. One valid question in this docket is whether these proposals are feasible and prudent considering their complexity. The HDA example mechanism provides a simpler alternative.

(b) HDA wants at least one decoupling mechanism to be considered in this docket that is designed exclusively to decouple utility earnings from variations in sales levels. The HECO and Consumer Advocate proposals include several features seemingly designed to reward the utility financially for diligent implementation of the renewable energy components of the HCEI and October 2008 Energy Agreement. Pending further verification, it appears that these mechanisms would increase rates and utility earnings. The objective of the HDA example mechanism is to decouple utility earnings from sales without substantially changing the value of the revenue stream recovered by the utility in the years between rate cases.

(c) HDA wants to provide a detailed example of the workings of a decoupling mechanism early in the proceeding to promote discussion of implementation details. Neither the HECO nor Consumer Advocate proposals outline in any detail the specific calculations that would be made in the context of a rate case or in application of the decoupling adjustments.

(d) HDA wants to engage a meaningful discussion of the initial and ongoing determination of fixed and variable costs and the relationship between average variable costs determined in the context of

[2] The live Excel spreadsheet used to generate the tables showing the workings of the decoupling mechanism in Attachment 2 is also being provided by electronic transmission to the parties and the Commission.

a rate case and the import of considering short run marginal costs in the context of application of a decoupling mechanism.

(d) The HDA example mechanism has previously been proposed to the Commission in the Energy Efficiency Docket and should be part of the discussion of decoupling.

The HDA example mechanism decouples sales from earnings. It does not decouple demand charges from earnings. A similar compatible mechanism could be designed to decouple demand revenues from changes in customer demand. This might be considered since the utilities will continue to implement the load management programs designed to reduce customer demand.

The HDA example mechanism decouples three customer classes (schedules R, G and J). These classes are typified by large numbers of smaller customers and are most appropriate for decoupling using a mechanism that relies on an index of number of new customers.

The large customer classes (PT, PP and PS) are already essentially decoupled since the marginal volumetric rates for these classes are close to short run marginal sales level generation costs. These customer classes are decoupled by existing rate design.[3] These customer classes are more difficult to decouple using an index of the number of new customers since average customer size is large and is not uniform.

Note that customer class schedule J is also mostly decoupled by way of short run marginal costs being close to marginal volumetric revenues. With minor adjustment to the rate design this customer class could be decoupled using a rate design approach. The schedule J class accounts for 20.6% of company volumetric energy charge revenues but only 3.4% of company fixed cost margin in volumetric revenues.[4]

The customer classes H and F are not decoupled but contribute little to the utility system fixed cost margins. See HDA Attachment 1.

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[3] Note that this is similar in effect to the "straight-fixed variable rate design" described in the NRRI decoupling scoping paper.

[4] These proportions are based on HECO's 2005 test year rate case as shown in HDA Attachment 1.

HDA Example Decoupling Mechanism

A mechanism is proposed to decouple utility earnings from fluctuations in utility sales volumes. This can be accomplished without substantially changing the value of the revenue stream recovered by the utility in the years between rate cases. This mechanism would make utility earnings ambivalent to changes in sales volumes (whether due to weather, business cycles or DSM program implementation by the utility or non-utility administrators) but would provide appropriate increases in recovery of the fixed cost component of revenues in proportion with the growth of the utility system between rate cases.[5]

With Hawaii's incumbent utility economics and rate design, energy utility earnings depend fundamentally upon the amount of energy sold. Increased energy consumption results in increased utility earnings. This is because, for both energy charges and demand charges, marginal revenues are greater than short run marginal costs. For each additional unit of energy provided by the utility it receives more additional revenue than its incremental costs to deliver the additional energy to its customers. Likewise, if sales levels decrease, utility revenues decrease by more than what the utility saves by not having to produce the unsold energy. This provides a powerful incentive for utilities to maintain sales levels during the interim periods between rate cases. It also provides a powerful disincentive to promote energy efficiency or customer sited generation measures that reduce energy consumption and result in reduced utility earnings.

The functional objective of the HDA example decoupling mechanism is to allow the net recovery of test year fixed costs embedded in volumetric charges to grow between rate cases along with the size of the utility system (as indexed by growth in the number of new customers). This would be in contrast to the existing regulatory compact that allows the recovery of revenues intended to compensate fixed utility costs to grow in as a function of the volume of energy sales.

DESCRIPTION OF THE PROPOSED DECOUPLING MECHANISM

A detailed example of the calculation and implementation of the HDA example mechanism is provided in HDA Attachment 2. This attachment is a reprint of a previous filing prepared by HDA for Rocky Mountain Institute the Energy Efficiency Docket No. 05-0069. Attachment 2 (and the accompanying live linked spreadsheet) shows the calculations that would be made in the context of a rate case (page 3), the periodic calculation of decoupling adjustments (page 4) and several demonstration scenarios that show how traditional methods and the HDA example decoupling mechanism would affect the collection of fixed and variable revenues under various assumptions (pages 5 and 6).

The HDA example mechanism is a "fixed charge per customer" earnings decoupling mechanism. It is designed to allow test year fixed costs (not revenues) to grow in proportion with utility system growth using an index of the number of new customers as a proxy for utility system growth between rate cases. Note that this mechanism is different than the "revenue per customer freeze" described in the HECO joint decoupling proposal.

- For purposes of implementing the decoupling mechanism the index of the number of customers would not be the same as the number of accounts. The number of customers used as an index in the mechanism is intended to serve as a proxy for the amount of growth on the utility system. In order to serve this specific purpose simply, without opportunity for gaming or spurious circumstances, the following conventions are suggested.
    - For each customer class the index of the number of customers would be equal to the test year number of customers plus the number of new customers at new premises. Ordinarily a building permit would be associated with each new customer.
    - Expiring customer accounts would not reduce the index of the number of customers[6] and new accounts at premises that previously received service would not be added.
    - Accounts generated by converting master metered buildings to individually metered accounts (or vice versa) would not change the index of the number of customers.
    - Customers moving from one customer class to another should be treated according to a reasonable convention that could be discussed.

[5] Adjustments to the fixed cost component in volumetrically billed revenues would not be symmetric. Fixed cost recovery would only be adjusted upward with increases in an index of customer growth. Adjustments for fluctuations in sales volume would be entirely symmetric.

[6] This is consistent with a premise that utility fixed costs do not decrease (in a one to three year time frame) if a customer disconnects or leaves the system.

- As initially implemented for HECO the decoupling mechanism could apply only to customer class Schedules R, G and J.
    - These three customer classes account for 94% of the fixed margins embedded in HECO's volumetric energy charges.[7]
    - Schedules PT, PP and PS are already essentially decoupled by way of marginal revenues being almost equal to marginal energy delivery costs. [See Attachment 1]
    - Schedule H and F comprise only a small fraction of HECO's energy revenues.
- The HDA example decoupling mechanism would not apply to demand charges. A similar and consistent mechanism could be designed to decouple utility earnings from changes in customer billing demand revenues. Several considerations regarding decoupling demand charges are listed below.
    - Demand charges account for 14.5% of HECO's total revenues. Energy charges account for 81.4% of total revenues. [See HDA Attachment 1]
    - Although energy efficiency, load management programs and customer sited as-available generation serve to reduce generation system level peak demand, only a portion of these demand reductions result in reductions in billed demand revenue.
        - For example, class and system level peak demand are reduced by energy efficiency measures that reduce the amount of time that fixed load motors or appliances operate. Customer metered demand, however, is not proportionally reduced by these measures.
        - Customer billed demand (that is based on metered demand) is not affected by load management programs that interrupt loads to reduce system peak loads.
        - HECO implements a one-year ratchet on its demand charges. For measures that do reduce customer metered demand, billed demand is not fully reduced for one year.

[7] See Attachment 1 for a breakdown of HECO fixed and variable costs embedded in volumetric rates by customer class according to information from HECO's 2005 test year rate case. At that time customer classes R, G and J accounted for 87.2%, 12/6% and 3.4% of the fixed cost margins in volumetric energy charges. Schedule J could be effectively decoupled with minor adjustments to existing marginal block rates.

- The HECO companies will administer the load management programs designed to reduce generation system level demand. To the extent that these programs do reduce customer billing demand, the existing rate design could present a disincentive to diligently implement load management programs.

DISCUSSION

It is important to note that the HDA example decoupling mechanism neither presumes nor is intended to provide completely accurate recovery of the utility's actual fixed costs that are incurred in the intervals between rate cases. The objectives of the decoupling mechanism are (a) to decouple utility earnings from sales volumes while (b) replicating, to a reasonably approximate degree, the value of the revenue stream provided by existing tariffs associated with system growth during the periods between rate cases. The existing tariffs do not accurately recover utility fixed costs between rate cases. The proposed decoupling mechanism does not attempt to "fix" or improve all aspects of the accuracy of the existing regulatory compact in this respect but rather to preserve the approximate magnitude of the value of the revenue stream.

It is also important to note that the proposed decoupling mechanism would affect utility revenues with respect to a broader set of factors than DSM program impacts. With existing tariffs utility revenues between rate cases are subject to many factors that affect utility sales volumes (and earnings) other than the utility's own DSM programs. These factors include weather, economic trends and cycles, customer responses to electricity prices (including fuel adjustment charges), customer adoption of conservation measures not sponsored by utility DSM programs, implementation of building codes, etc. The decoupling mechanism would tend to stabilize utility revenues with respect to most of these existing sources of revenue variability. The stabilization and reduction in uncertainty of utility revenues provided by the decoupling mechanism between rate cases constitutes an increase in the value of the revenue stream (all other things being equal).

The implementation of the proposed decoupling mechanism would be similar in several fundamental respects to the existing energy cost adjustment clause (ECAC) and would be no more complicated to administer on an ongoing basis. Similar to the ECAC the proposed mechanism is a regular periodic adjustment to energy charges that is applied automatically in customer bills by a line item surcharge. The proposed mechanism is also similar to the ECAC in the respect that it is based upon a small number of exogenous and simply determined parameters (actual sales and number of customers for each affected customer class).

See the text and tables in HDA Attachment 2 for a detailed explanation and example of the implementation of the HDA example decoupling mechanism.

2.1. Should the decoupling process decouple the utility's earnings (or revenues) from the effects of changes in weather, economic upturns/downturns, taxes, costs of financing, the utility's credit rating or other external variables? How are the sales impacts of efficiency programs segregated from these factors, and how does the commission monitor these factors going forward?

RESPONSE:

As a practical matter, decoupling should decouple the utilities' earnings from all factors that affect sales levels. This comprehensive insulation from all factors that affect sales is not a principal objective of decoupling but is necessary because it is not practical to segregate the impacts of these factors from factors that are directly caused by the actions of the utility.

The sales impacts of the efficiency programs should not be methodically segregated from these factors or monitored on an ongoing basis (except perhaps in other venues for the purpose of DSM program evaluation and planning).

Decoupling utility earnings from all of these factors is not undesirable as long as the change in the value of the resulting cost stream associated with shifting these financial risks between the utility and utility customers is recognized and properly reallocated.

2.2. Does decoupling that ensures a utility's earnings associated with lost sales create a disincentive for utilities to manage these costs effectively or to invest in capital projects rather than purchase energy or other services?

RESPONSE:

Decoupling utility earnings from fluctuations in sales does not, in itself, create any disincentive for utilities to manage costs effectively or allocate capital efficiently. HDA notes, however, that particular aspects of some decoupling proposals could have some of these effects. A decoupling mechanism should insulate earnings from changes in sales (and/or demand) levels between rate cases. It should not ensure any level of earnings regardless of utility cost management or capital allocation decisions.

2.3. Does it eliminate the utility's bias against reduced sales?

RESPONSE:

Yes. The HDA example mechanism removes the utilities' bias against reduced sales.

2.4. Does it accurately decouple sales and earnings (i.e., reinstate authorized earnings associated with lost sales)? Please provide supporting examples and calculations that address how lost earnings are calculated.

RESPONSE:

Yes. See HDA Attachment 2 at pages 5 and 6. These pages show calculations of energy charges under several assumed scenarios regarding sales and customer growth rates and according to both traditional and the HDA example decoupling mechanism. The calculations on these tables are linked to the example test year calculations on page 3 and the periodic calculation of the decoupled energy charge adjustments on page 4 of the Attachment. A live spreadsheet of these linked tables is provided.[8] The numbers in the demonstration examples on pages 5 and 6 are taken directly from the preceding test year and decoupling adjustment calculation tables.[9]

On page 5 a comparison of energy charge revenues is provided for customer classes R, G and J under both existing traditional recovery and recovery decoupled according to the HDA example mechanism. The calculations demonstrate that under the HDA example mechanism the net revenues recovered by the utility to cover fixed costs (total revenues minus production costs) equal test year fixed costs times the growth in the number of customers.

On page 6 of HDA Attachment to a comparison of energy charge revenues for customer class R is provided under a variety of assumptions for both traditional and the HDA example decoupling recovery methods. These calculations show that the utility fixed costs are accurately recovered regardless of fluctuations in sales. The fixed costs are effectively decoupled from sales fluctuations.

2.5. Does it encourage customers to be energy efficient?

RESPONSE:

The decoupling mechanism, by itself, does not encourage customers to be energy efficient except to the extent that incremental increases in rates that would result from decreased sales (other things being equal) would increase incentives to conserve energy. Note, however, that if utility sales increase faster than the rate of growth of new customers, rates would be decreased incrementally.

2.6. Is it easy to understand?

RESPONSE:

It is much easier to understand than the HECO/DCA proposal. It is a straightforward mechanism that should be understandable to regulators. Decoupling, generally, is not very easy to understand.

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[8] The numbers in the demonstration examples on pages 5 and 6 are taken directly from the preceding test year and decoupling adjustment calculation tables on pages 3 and 4. The production costs used in the "actual" examples are equal to the test year production costs plus (or minus) the short run marginal unit costs (sales level) times the difference between test year sales and actual sales.

[9] The production costs used in the demonstration examples on pages 5 and 6 are equal to the test year production costs plus (or minus) the short run marginal unit costs (sales level) times the difference between test year sales and actual sales. This properly recognizes that utility costs of production associated with changes in sales volume are the customer class specific sales level short run marginal production costs. The sales level marginal costs in the examples are adjusted for each customer class to account for transmission, distribution and transformation losses based on information from the HECO 2005 test year rate case filing. The citation for the marginal sales level energy costs on page 3 of Attachment 2 should be HECO-RWP-2214, p.2 as properly noted in HDA Attachment 1.

2.7. Are Hawaii's electric utilities' existing metering and customer service systems adequate to support decoupling? If no, recommend enhancements.

RESPONSE:

Yes, assuming that the existing billing system can accommodate a new line item surcharge adjustment on customer bills.

2.8. Is it easy to administer (monitoring, audits, hearings, reconciliation)? Estimate the administrative costs including regulatory costs.

RESPONSE:

The decoupling mechanism proposed by HDA is a relatively simple mechanism to administer. It would be much simpler and less expensive to administer than the HECO and DCA proposals.

The administration of this mechanism would be similar to and less expensive to administer than the existing Energy Cost Adjustment Charge (ECAC) mechanism. It would not require any monitoring, audits, hearings or reconciliation beyond what is required for the existing ECAC mechanism.

2.9. If the proposed method herein is different from the method proposed by the Agreement, why is it superior?

RESPONSE:

HDA reserves judgment regarding whether the HDA example mechanism is "superior" until the nature of the HECO and Consumer Advocate's proposals are better understood and other parties have an opportunity to offer other alternatives and state their concerns. At this point HDA notes the following advantages of the HDA example mechanism:

(a) It is much simpler.

(b) It is easier and less costly to administer.

(c) It is revenue neutral (rather than providing additional revenues to the utility).

(d) It accurately and completely decouples earnings from sales fluctuations between rate cases (which, pending verification of details, the HECO proposal apparently may not)[10]

(e) It is less subject to gaming.

3. What actions, if any, are required to identify with accuracy each utility's fixed and variable costs?

RESPONSE:

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[10] Based on HDA's initial examination of HECO's proposal, it appears that the HECO rate adjustment mechanism (RAM) would include some fuel and purchased power costs in the "fixed" component of RAM revenues. Pending verification of these details HDA is not confident that the HECO proposal would accurately and effectively decouple earnings from sales fluctuations. The DCA proposal does not include specific details sufficient to make any determination.

Fixed and variable costs and marginal cost components are identified and are broken down by customer class in a typical utility rate case application (including associated exhibits and workpapers). See HDA Attachment 1 for an example of a breakdown of fixed and variable costs for each customer class with citations to information taken from exhibits and workpapers in HECO's 2005 test year rate case.

Short run marginal production costs can be determined by a differential revenue requirements production cost analysis such as that conducted by the utilities to determine energy efficiency program impacts and cost-effectiveness. See for example HDA Attachment 3 which shows the results of a differential revenue requirements analysis presented by HECO in the Energy Efficiency Docket. This analysis shows the long run marginal capacity and energy avoided costs resulting from implementation of a portfolio of energy efficiency and load management (DSM) programs. As verified on the record of the Energy Efficiency Docket, in the years prior to 2015 (the date of the first supply side resource online date affected by the implementation of the DSM programs), the Avoided Energy Costs in column 11 on page 1 of HDA Attachment 3 are the short run marginal costs of energy (net-to-system level) for HECO.

3.1. What fixed charges are recovered through the utility's volumetric rates by rate component?

RESPONSE:

See HDA Attachment 1 which shows the fixed and variable charges recovered through the various components of rates for each customer class. This table is based on HECO's 2005 test year rate case. HDA has not developed similar information based on HECO's most recent rate case. The fixed charges recovered in volumetric rates are shown for each rate class in the row titled "Non-Fuel/Purch.Energy in Energy Charges". These charges are shown in annual dollars, in unit per KWH rates and as percentages of class energy charges, class revenues, company revenues and as a percentage of company total fixed margins.

Note that, as a separate calculation, HDA Attachment 1 identifies the "fixed margin" embedded in volumetrically billed energy charges. The fixed margin is the difference between the energy charge in the marginal block and the customer class sales level short run marginal cost of delivered energy. Fixed margins determine a utility's actual incentives to maintain sales volume. As long as marginal volumetric rates are greater than the costs to deliver energy, the utility will have an incentive to maintain sales volume.

3.2. Is the information needed to allocate costs into fixed and variable costs included in a current rate filing? If yes, please provide.

RESPONSE:

Except as noted below, the information needed to allocate costs into fixed and variable costs in typically included in a rate case. See HDA Attachment 1 for an example of this determination (with citations for the HECO 2005 test year rate case). HDA has not compiled citations for this information from the pending HECO rate case.

In addition to the information provided in a typical rate case, a good determination of short run marginal costs should be made using a differential revenue requirements analysis as is done in determining the costs and benefits of energy efficiency programs. See response to Question 3 above and HDA Attachment 3 for an example of the analysis provided by HECO in the Energy Efficiency Docket.

3.3. How should the Commission differentiate between fixed and variable costs?

RESPONSE:

Fixed and variable costs are tabulated in a typical rate case. For purposes of implementing a decoupling mechanism, the fixed costs to be maintained by the mechanism would be:

Rate case test year revenue requirements minus fuel and purchased power expenses.[11]

If the objective of the decoupling mechanism is to make the utility ambivalent to changes in the amount of energy sales (earnings decoupling), the decoupling mechanism should be applied using short run marginal costs as a determinant of the decoupling adjustments. Short run marginal costs represent the costs to the utility for providing one additional increment of energy (or, equivalently, the savings from producing one less increment of energy). In order for a decoupling mechanism to provide the amount of fixed costs determined in the test year rate case it is necessary to use short run marginal costs as the determinant in the application of the decoupling mechanism for adjustments between rate cases. This is demonstrated in HDA Attachment 2 showing the application of short run marginal costs in a decoupling mechanism applied to HECO's system (pages 3 and 4) and the resulting revenue recovery under several hypothetical scenarios (pages 5 and 6).

Short run marginal costs can be determined using a differential revenue requirements analysis such as the analysis used to determine the costs and benefits of energy efficiency programs. See response to Question 3 above and HDA Attachment 3. As applied in the HDA example decoupling mechanism shown in HDA Attachment 2, the actual short run marginal costs are properly adjusted on an ongoing basis by the ECAC. The example mechanism is transparent to and consistent with the ECAC mechanism.

3.3.1. What timeframe should the Commission consider in setting fixed and variable costs?

RESPONSE:

The three year rate case cycle in the HECO proposal is reasonable. The frequency of the need to determine fixed and variable costs depends on the specific decoupling mechanism. In the mechanism proposed by HDA the fixed costs would be determined once in the rate case each three years. Short run marginal costs would be determined once in each rate case using a differential revenue requirements analysis. Monthly ECAC adjustments as currently implemented would provide appropriate adjustments to marginal costs on an ongoing basis until the next rate case without any need for further adjustments to the marginal costs used in the decoupling adjustments. If utility generation facilities or other changes are made to the system that would change system

[11] For purposes of decoupling this simple approach may be sufficient. A more rigorous calculation could include other expenses that change with changes in production volume within the three year time frame between rate cases.

short run marginal costs these costs could be recalculated as needed by differential revenue requirements analysis.

3.3.2. Are some "fixed costs" simply long-run variable costs that appear fixed in the short term and how should this affect decoupling?

RESPONSE:

Yes, but if a three year rate case cycle is adopted as recommended by HECO, this should not be a major factor. If there are appreciable costs that are variable with respect to the level of energy production within a three year period these could be included in the calculation of variable costs and short run marginal costs used in determining decoupling adjustments.

3.4. To what extent, if any, should the Energy Cost Adjustment Clause (ECAC) be modified if decoupling is enacted? Are any fixed costs recovered via the ECAC, and if so, should they be removed? To what extent should performance incentives inherent in the clause be modified or removed in order to remove the connection between utility sales and earnings? Should these incentives instead be recovered through the other charges?

RESPONSE:

The decoupling mechanism proposed by HDA is designed specifically and deliberately to be transparent to and consistent with the existing ECAC mechanism.

Fixed costs are not recovered by the ECAC.

The ECAC is actually a fuel price adjustment mechanism and does not directly pass through any actual costs (variable or fixed). Because the ECAC mechanism is a fuel price adjustment mechanism (not a straight cost pass through) the existing incentives in the ECAC encourage the utility to operate its system at the most efficient level from a thermodynamic perspective (minimum BTU consumption). This incentive would not be perturbed by the decoupling mechanism proposed by HDA. For this reason, all other things being equal, the utility would still have some residual incentive in favor of lower sales and demand to the extent that this would allow the generation system to operate more efficiently from a thermodynamic standpoint. The existing ECAC mechanism would not have to be adjusted if the decoupling mechanism proposed by HDA were implemented.

It is not possible for HDA to determine, based on the details provided so far, how the HECO or DCA proposed decoupling mechanisms would interact with the existing ECAC mechanism.

4. What level of specificity is required on a customer's bill to support a decoupling adjustment (e.g., if allocated by rate component, should there be a line item for each part of the decoupling adjustment on the bill)?

RESPONSE:

One line showing the amount of the decoupling adjustment should be sufficient. Because decoupling is not likely to be understood in detail by most customers, more information on customer bills would not useful.

It might be useful for the utility and/or the Consumer Advocate to post a page on a web site that explains the workings of the decoupling mechanism shows the components of the adjustments made to rates for each rate class since the last rate case.

5. Do all customers share in the benefits of improved energy efficiency, or only those customers who improve their own energy efficiency?

RESPONSE:

All customers receive <u>some</u> long range benefit from the implementation of improved energy efficiency in terms of deferred utility capital expenditures and avoided operating costs if the measures (or programs) are cost effective according to the utility cost test. All customers receive <u>net</u> benefits, however, only if the measures or programs are cost effective according to the ratepayer impact measure test (sometimes referred to as the non-participant cost test). Non-participants only have a net benefit if the program lowers rates in the long term... which means the savings to the utility (utility avoided capacity and avoided operating costs) are greater than the costs of the efficiency programs that are included in utility bills and the upward pressure on rates from reductions in sales volumes.

Customers who implement measures or participate in programs that are cost effective according to the participant cost test will receive net benefits.

5.1. What does the allocation of benefits indicate about the allocation of decoupling's earnings adjustments?

RESPONSE:

HDA suggests that decoupling should be implemented on a class by class basis. The objective is to make the utility ambivalent (regarding earnings) regarding sales volumes for each class. Since each class has different proportions and absolute amounts of fixed costs embedded in volumetrically billed rates, it is necessary to apply the mechanism individually for each class. This should allocate impacts properly to each class individually without cross class impacts.

5.2. How should the Commission consider each utility's capacity and energy availability in determining the allocation of the decoupling adjustment?

RESPONSE:

See response to previous question.

5.3. Please propose and discuss an allocation methodology for the decoupling methodology proposed at question 2, above. Include responses to the following questions.

RESPONSE:

The HDA example mechanism adjusts each customer class fixed margins separately.

5.3.1. How much of the anticipated change in sales is driven by utility-sponsored programs? Are the programs available to all classes of customers? How are these costs allocated?

RESPONSE:

These questions are relevant to good DSM program design but are not applicable to the HDA example mechanism. The HDA example mechanism does not differentiate between causes of sales fluctuations. The utility is effectively decoupled from all factors that affect sales levels.

5.3.2. Can the utilities' net metering protocols allow behind-the-meter renewable energy to be tracked as a distinct cause of lost sales?

RESPONSE:

The utility net metering protocols allow the utility to track net customer electric demand but not the amount of energy generated on the customer side of the meter.

5.3.3. Does customer growth or attrition mask or exaggerate actual energy efficiency trends?

RESPONSE:

This is not applicable to the HDA example mechanism.

5.3.4. Aside from utility-sponsored programs, do all classes of customers have the same cost-effective opportunities for energy efficiency improvements?

RESPONSE:

No. This question is relevant to good DSM program design is not applicable to the HDA example mechanism which does not differentiate between the many factors that affect sales levels and does not specifically allocate decoupling adjustments between classes. Each class is decoupled separately.

5.3.5. Can and should the decoupling charge be allocated to promote specific energy efficiency goals such as cutting peak demand or reducing carbon emissions?

RESPONSE:

Perhaps, but this is not a feature of the HDA example mechanism. The HDA example mechanism attempts to provide a simple decoupling option and does not attempt to implement other objectives.

5.3.6. Does energy efficiency offer greater benefits to the economy in one sector than in another?

RESPONSE:

Yes, but see response to Question 5.3.4 above.

5.3.7. The utilities contend that some rate classes produce higher rates of return than others do. To the extent that these differences exist, how should they be addressed under the proposed decoupling process?

RESPONSE:

This is not addressed by the HDA example mechanism.

6. Should the Commission allow the full recovery of lost earnings though the decoupling adjustment or only some percentage of the calculated lost earnings? How much of the risk associated with a change in sales should remain with the utility?

RESPONSE:

The HDA example mechanism fully decouples earnings from sales fluctuations. This is an appropriate objective. It would be a simple matter to implement the HDA example mechanism so that it only partially decouples earnings from sales fluctuations or so that it only partially "recouples" fixed cost recovery to utility system growth.

6.1. If there is a deviation from 100% recovery, should the deviation be symmetric? For example if sales decrease, does the utility receive 75% of the calculated lost earnings but when sales increase, customers get 100% of the adjustment?

RESPONSE:

The HDA example mechanism fully and symmetrically decouples earnings from sales fluctuations.

The mechanism is not symmetric, however, regarding increasing the recovery of the fixed cost component of revenues. The index of the number of customers used to determine growth in recovery of fixed costs is only allowed to increase.

This principal regarding adjustment symmetry could perhaps apply to setting earnings caps as proposed by the Consumer Advocate.

6.2. How does a partial adjustment help meet the goals of the Clean Energy Initiative?

RESPONSE:

HDA does not suppose that it does.

7. How much, if any, of a rate-of-return adjustment is commensurate with the greater certainty in earnings provided by decoupling?

RESPONSE:

HDA has not calculated this. As anticipated by the subparts to the question, the increased stability of the net revenue stream to the utility could be calculated and incorporated in the quantification of risk used to determine the utility return on equity.

7.1. To the extent that decoupling results in less financial risk for the utility, how should the commission quantify that effect and how should this be flowed through to the utility's rate of return?

RESPONSE:

See response to Question 7. above.

7.2. Please quantify decoupling's effect on the utilities' "beta" (a measurement of risk) and what that means to the utility's return and ability to move to a capital structure with more debt.

RESPONSE:

See response to Question 7. above.

7.3. Can input from the rating agencies be included during development of the decoupling process?

RESPONSE:

HDA has no worthwhile response.

8. Some customers may not have the same opportunity to conserve electricity as other customers because differences such as income, access to capital, age, and renting versus owning. How should decoupling adjustments be structured to address this lesser ability to conserve?

RESPONSE:

This question is relevant to good DSM program design is not applicable to the HDA example mechanism. The HDA mechanism does not have, as a design objective, addressing equity issues regarding implementation of DSM programs.

9. Please propose a customer education program for the decoupling mechanism proposed at question 2 and the allocation methodology proposed at 5.2.

RESPONSE:

HDA is not prepared to propose a customer education program at this time.

The most effective single action that could be taken to promote the acceptance of decoupling would be to reverse the decision made by HECO to forego adjustment of its test year sales forecast in its pending rate case.

In its pending rate case, HECO has "offered to forego updating rate case sales" to reflect that fact that actual and forecast sales are now expected to be lower than test year sales assumptions.[12] It is thus proposed that test year sales would be higher than known and expected. This would make

[12] See Consumer Advocate's HECO/MECO/HELCO Rate Adjustment Mechanism "RAM" Conceptual Framework Proposal at page 2, footnote 4.

base rates lower than if the test year forecast were adjusted and would make corresponding decoupling adjustments greater in magnitude and mostly upward.

To the extent that public acceptance of any decoupling adjustment mechanism is important, it would be better to adjust the test year forecast downward to known and expected estimates (1) making base rates higher, (2) making the magnitude of decoupling adjustments smaller, (3) making decoupling adjustments more likely to be downward as often as upward and (4) ostensibly having the same result in terms of revenue and earnings.[13]

10. To the extent that the decoupling mechanism is intended to help reduce energy consumption, can this adversely affect the state's efforts to incorporate more as-available renewable energy into the grid? Can reduced consumption cause more instances where as-available energy must be curtailed due to the utility's system constraints?

RESPONSE:

It is true that lower consumption could lead to more curtailment of renewable generation due to minimum load conditions. HDA would maintain that this is a good argument for load shifting programs but not a good argument for load building programs. Hawaii should not encourage energy consumption or discourage energy efficiency to maintain more persistent renewable generation.

11. Do the rate changes associated with the decoupling mechanism merit a new rate case for HECO pursuant to Hawaii Revised Statutes, Chapter 269, or can the changes be accomplished within the scope of the existing HECO rate case? Are public hearings needed, considering the extent of the expected rate changes?

RESPONSE:

HDA does not state a position on this as a legal matter. Several aspects of HECO's rate case might be expected to change as a result of the decisions in the decoupling docket including, for example, revisions to the determination of the utility return on equity to account for changes in the allocation of financial risks resulting from decoupling and/or the proposed RAM adjustments.

12. Various provisions of the HCEI propose utility surcharges, where the utility will fairly immediately recover its costs (potentially both fixed and variable) through a surcharge that is separate from the normal rates. How can the commission effectively decouple this aspect of the utility rates? Do these surcharges impact the effectiveness of the efforts to decouple rates from earning?

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[13] Based on HDA's current understanding of HECO's decoupling proposal, however, (which is tentative and still needs to be verified), if HECO would reverse its decision and adjust the test year sales forecast to recent and expected levels this would also lower total rates ultimately paid by HECO's customers and decrease HECO's earnings. According to HDA's current (and incomplete) understanding, HECO's proposed mechanism would not accurately decouple earnings from sales volumes.

RESPONSE:

HDA presumes (and certainly hopes) that the surcharges would be subject to ex poste adjustment of actual recovery compared to recovery projected based on estimated sales. In this sense the surcharges would be effectively "decoupled" because, regardless of actual sales, the proper authorized amount of recovery would eventually be recovered accurately.

HDA notes that there are potential issues that should be considered regarding the relationship between the surcharges and the decoupling mechanisms. If substantial amounts of generation costs are recovered through surcharges (such as a feed-in tariff surcharge) there are several potential resulting complications and spurious incentives that should be considered in the design of a decoupling mechanism. For example, if the utility has discretion over whether to provide generation by its own resources or by resources billed by through a surcharge, or if these proportions are not known at the time of a rate case, the design of the decoupling mechanism must ensure that reasonably accurate recovery of utility fixed costs will be maintained in any case. If the decoupling mechanism includes fuel or purchased power costs in the amount of revenues that are to be decoupled (held constant with respect to changes in sales) utility earnings would be substantially affected by differences between the assumed versus the actual amount or proportion of energy provided by generation recovered through the surcharges.

All of the proposed decoupling mechanisms should be carefully examined to determine transparency and consistency with existing and proposed surcharges and other rate design features.

12.1 Please provide details of changes that need to be made to the various HCEI proposals that have already been filed as a result of decoupling.

RESPONSE:

HDA is not aware of any necessary changes.

Revenue Components and Energy Costs by Customer Class

Based on RMI FSOP Exhibit E, revised (8/19/2006), Docket No. 05-0069

Hawaiian Electric Company - Fixed Margin Based on Energy Charges in Marginal Block

HECO 2005 TEST YEAR RATE CASE

Source information based on HECO response to RMI/HECO-IR-20: revised filings in HECO's rate case application in Docket No. 04-0113 (Revenue at Proposed Rates)

Customer Class =>	**R/E**	**G**	**J**	**H**	**PT**	**PP**	**PS**	**F**	**Total**	% Total	**Source**
Test Year Sales (MWH)	2,154,400	377,500	2,013,000	53,400	173,740	2,168,528	875,132	40,300	7,856,000		HECO-R-2216 thru 2223
Avg. Energy Charges (billed per KwH)	$373,396	$61,388	$263,590	$7,400	$19,425	$246,855	$100,115	$6,741	$1,078,910		HECO-R-2216 thru 2223
Energy Charge in Marginal Block	$0.1733	$0.1626	$0.1146	$0.1386	$0.1068	$0.1087	$0.1085	$0.1489			HECO-R-2216 thru 2223
As percentage of Class Revenues	92.4%	81.9%	81.5%	82.6%	81.0%	80.1%	76.9%	98.7%	84.3%		
As percentage of Company Revenues	*29.2%*	*4.8%*	*20.6%*	*0.6%*	*1.5%*	*19.3%*	*7.8%*	*0.5%*	*84.3%*		
Fuel and Purchased Energy Costs (w.taxes)	$189,183	$33,146	$176,164	$4,692	$14,643	$184,457	$76,278	$3,451	$682,014		HECO-RWP-2201 p.1/90
Unit costs (per Kwh)	$0.0878	$0.0878	$0.0875	$0.0879	$0.0843	$0.0851	$0.0872	$0.0856	$0.0868		
As percentage of Class Energy charges	50.7%	54.0%	66.8%	63.4%	75.4%	74.7%	76.2%	51.2%	63.2%		
As percentage of Class Revenues	46.8%	44.2%	54.5%	52.3%	61.0%	59.9%	58.6%	50.5%	53.3%		
As percentage of Company Revenues	14.8%	2.6%	13.8%	0.4%	1.1%	14.4%	6.0%	0.3%	53.3%		
Non-Fuel/Purch.Energy in Energy charges	$184,213	$28,242	$87,426	$2,708	$4,782	$62,398	$23,837	$3,290	$396,896		
Unit costs (per Kwh)	$0.0855	$0.0748	$0.0434	$0.0507	$0.0275	$0.0288	$0.0272	$0.0816	$0.0505		
As percentage of Class Energy charges	49.3%	46.0%	33.2%	36.6%	24.6%	25.3%	23.8%	48.8%	36.8%		
As percentage of Class Revenues	46.8%	44.2%	54.5%	52.3%	61.0%	59.9%	58.6%	50.5%	53.3%		
As percentage of Company Revenues	14.8%	2.6%	13.8%	0.4%	1.1%	14.4%	6.0%	0.3%	53.3%		
As percentage of Fixed Margin	46.4%	7.1%	22.0%	0.7%	1.2%	15.7%	6.0%	0.8%	100.0%		
Marginal Energy Costs (sales level)											
Unit costs (per Kwh)	$0.1121	$0.1121	$0.1121	$0.1121	$0.1070	$0.1108	$0.1121	$0.1121			HECO-RWP-2214 p.2
As percent Marginal Block Energy Charge	**64.7%**	**68.9%**	**97.8%**	**80.9%**	**100.2%**	**101.9%**	**103.3%**	**75.3%**			
As percentage of Average Energy Costs	127.7%	127.7%	128.1%	127.6%	127.0%	130.3%	128.6%	130.9%			
Fixed Margin (Marg. En.Charge-Marg. En.Cost)	$131,888	$19,070	$5,091	$1,414	-$35	-$4,474	-$3,148	$1,484	$151,290		
Unit costs (per Kwh)	$0.0612	$0.0505	$0.0025	$0.0265	-$0.0002	-$0.0021	-$0.0036	$0.0368			
As percent Marginal Block Energy Charge	**35.3%**	**31.1%**	**2.2%**	**19.1%**	**-0.2%**	**-1.9%**	**-3.3%**	**24.7%**			
As percentage of Class Revenues	32.6%	25.4%	1.6%	15.8%	-0.1%	-1.5%	-2.4%	21.7%	11.8%		
As percentage of Company Revenues	**10.3%**	**1.5%**	**0.4%**	**0.1%**	**0.0%**	**-0.3%**	**-0.2%**	**0.1%**	**11.8%**		
As percentage of Fixed Margin	**87.2%**	**12.6%**	**3.4%**	**0.9%**	**0.0%**	**-3.0%**	**-2.1%**	**1.0%**	**100.0%**		
Demand Charges (billed per Kw)			$57,412	$958	$4,689	$65,262	$30,388		$158,709		HECO-2218 thru 2225
As percentage of Class Revenues			17.8%	10.7%	19.5%	21.2%	23.3%		12.4%		
As percentage of Company Revenues			**4.5%**	**0.1%**	**0.4%**	**5.1%**	**2.4%**		**12.4%**		
Revenue at Proposed Rates											
Energy charges (billed per kWh)	$373,396	$61,388	$263,590	$7,400	$19,425	$246,855	$100,115	$6,741	$1,078,910	**84.3%**	HECO-R-2216 thru 2223
Demand charges (billed per kW)			$57,301	$958	$4,700	$65,422	$30,462		$158,843	**12.4%**	HECO-R-2216 thru 2223
Customer charges (billed per account)	$30,933	$13,617	$5,479	$611	$19	$796	$798	$97	$52,350	4.1%	HECO-R-2216 thru 2223
Adjustments	-$203	-$35	-$1,571	-$6	-$155	-$3,248	-$1,023	-$10	-$6,251	-0.5%	HECO-R-2216 thru 2223
Riders			-$1,398		$0	-$1,742	-$157		-$3,297	-0.3%	HECO-R-2216 thru 2223
Total Revenues	$404,126	$74,970	$323,401	$8,963	$23,989	$308,083	$130,195	$6,828	$1,280,555	100.0%	HECO-R-2216 thru 2223

HECO/RMI-FSOP-IR-132: Ref: RMI FSOP, Exhibit B, page 5. Fuel Energy Charge, including footnote 3. HECO's current energy charges recover test year estimates of total fuel and purchased power expense and some portion of test year estimates of fixed costs. The RMI proposal example shows Fuel Energy Charge = Test year marginal delivered energy cost. Does the RMI proposal intend to recover marginal energy costs instead of estimated test year total energy costs? If so, explain why. If not, please show how the proposed fuel energy charge would be calculated for HECO's Schedules R, G, and J without marginal energy cost data, and please provide all references for each calculation.

RMI RESPONSE (Carl Freedman): No, the RMI proposal does not intend to recover marginal energy costs rather than estimated total test year total energy costs. As stated in the RMI FSOP the magnitude of the energy charges (customer charges billed on the basis of kilowatt-hour sales) would be calculated in a general rate case using the same methods presently used. The total energy charge would still be equal to the estimated test year unit energy costs for each rate class (which, as noted in the information request, includes both variable and fixed cost components). The RMI proposal differs from HECO's existing rate design in the respect that the energy charge would be divided into two components with one component adjusted based on the number of customers (for each applicable class). It is the division of the energy charge into these two components that is based on the marginal energy costs. The total energy charge remains based on test year unit energy costs.

As requested, attached below are several tables that demonstrate how the proposed fuel energy charge would be calculated for HECO's Schedules R, G, and J. Marginal energy data are used in the calculation of the decoupling mechanism. References are provided. The first table shows how the necessary determinations to support the decoupling mechanism would be made in the context of a general rate case or based on information from a general rate case. The second table shows how the decoupling mechanism would be applied in each periodic application between rate cases. The example is for an annual period but the mechanism could be also be implemented on a monthly or quarterly basis. The third and fourth tables show the resulting revenue streams that result from the mechanism depicted. Explanatory notes are provided on the tables.

The mechanism depicted implements the decoupling method and equations described in the RMI FSOP and exhibits except that (1) the equations in the mechanism depicted here have been put in the form of energy charge adjustments similar in form and application to HECO's existing ECAC mechanism and (2) necessary detail in the form of the equations has been added in implementing equations. Putting the equations in the form of an energy charge adjustment provides a method of implementing the mechanism that is transparent to other rate design features (including the ECAC), is generally familiar to the Hawaii utilities and regulators and is feasible to implement by existing billing formats and procedures.

Alternate mechanisms have been developed by RMI. The particular method depicted here follows most closely to the principle described in the RMI FSOP and exhibits that net recovery of test year non-fuel expenses included in the energy charge (after production costs are covered) will track and increase in proportion with an index of the number of customers. Sales volumes do not affect the net revenues of the utility. This is demonstrated on the third and fourth tables.

The data in these revised tables are amended based on HECO's responses to RMI's information requests including, in particular, RMI/HECO-IR-20.

Determination of Decoupled Test Year Energy Charges In General Rate Case

Hawaiian Electric Company - Fixed Margin Based on Marginal Energy Costs **Method #1**

Source data are from RMI/HECO-IR-20; revised HECO filings in Docket No. 04-0113 (Revenue at Proposed Rates)

Line	**Customer Class =>**	**R/E**	**G**	**J**	**Source**
A	Test Year Sales (MWH)	2,154,400	377,500	2,013,000	HECO-R-2216 thru 2223
B	Avg. Energy Charges (billed per KwH)	$373,396	$61,388	$263,590	HECO-R-2216 thru 2223
C	Energy Charge in Marginal Block	$0.1733	$0.1626	$0.1146	HECO-R-2216 thru 2223
D	Fuel and Purchased Energy Costs (w.taxes)	$189,183	$33,146	$176,164	HECO-RWP-2201 p.1/90
E	Unit costs (per Kwh)	$0.0878	$0.0878	$0.0875	D / A
F	Non-Fuel/Purch.Energy in Energy charges	$184,213	$28,242	$87,426	B - D
G	Unit costs (per Kwh)	$0.0855	$0.0748	$0.0434	F / A
H	Marginal Energy Costs (sales level)	$241,508	$42,318	$225,657	J * A
J	Unit costs (per Kwh)	$0.1121	$0.1121	$0.1121	HECO-R-2216 thru 2223
K	Fixed Margin (Marg. En.Charge-Marg. En.Cost)	$131,888	$19,070	$37,933	B - H
L	Unit costs (per Kwh)	$0 0612	$0.0505	$0.0188	H / A
	Test Year Energy Charges (Decoupled)				
N	Total Energy Charge (Marginal Block)	$0.1733	$0.1626	$0.1146	C
P	**Fuel Energy Charge**	**$0.1121**	**$0.1121**	**$0.1121**	J
Q	**Non-Fuel Energy Charge (Fixed Margin)**	**$0.0612**	**$0.0505**	**$0.0188**	C-J
R	Total Energy Charge (Base Block)			$0.1364	HECO-R-2218
S	**Non-Fuel Energy Charge (Base Block)**			**$0.0243**	R - J
T	Total Energy Charge (Middle Block)			$0.1249	HECO-R-2218
U	**Non-Fuel Energy Charge (Middle Block)**			**$0.0128**	T - J

This table shows the determinations that would be made in a general rate case that would serve as the basis for subsequent periodic calculation of decoupled energy charges. The parameters that would be determined specifically for application to later periodic adjustments are the Fuel Energy Charge and the Non-Fuel Energy Charges. These are shown on lines P, Q, S and T. The other parameters shown that are used in later periodic adjustments are already determined in the general rate case by existing practices. The Non-Fuel Energy Charge shown on line Q is the charge for the high consumption block (marginal block) for Schedule J.

Lines E and G break out total energy charges into base fuel and non-fuel components approximately according to HECO's existing methods. The base fuel energy charge based on average energy costs would continue to be used as the basis for application of the ECAC.

Marginal costs in this table are derived from HECO-2211 and are used here for expository purposes. Appropriate marginal costs that represent the unit change in energy cost associated with a unit change in KWH delivered energy (sales level) need to be identified and applied.

Periodic Calculation of Decoupled Energy Charge Adjustment — Method #1

Hawaiian Electric Company - Fixed Margin Based on Marginal Energy Costs

Source data are from RMI/HECO-IR-20: revised HECO filings in Docket No. 04-0113 (Revenue at Proposed Rates)

Line	Customer Class =>	R/E	G	J	Source
A	Test Year Sales	2,154,400	377,500	2,013,000	HECO-R-2216 thru 2223
B	Actual Sales	2,262,120	396,375	2,113,650	Hypothetical
C	Sales Growth Factor	1 05	1.05	1.05	B / A
D	Decoupling Factor (Sales)	-0.0476	-0.0476	-0.0476	(A / B) - 1
E	Test Year Non-Fuel Energy Charge (Marginal Block)	$0.0612	$0.0505	$0.0188	Test Year Determination
F	Decoupling Adjustment Subtotal	($0.0029)	($0 0024)	($0.0009)	D * E
G	Test Year Number of Customers	257,648	25,629	6,680	HECO-201
H	Actual Index of Customers	265,377	26,398	6,880	Hypothetical
J	Customers Growth Factor	1.03	1.03	1.03	H / G
K	Customer Factor	0.0300	0.0300	0.0300	(H / G) - 1
L	Test Year Non-Fuel Expenses in Energy Charges	$184,213	$28,242	$87,426	Test Year Determination
M	Incremental Non-Fuel Revenues	$5,526	$847	$2,623	K * L
N	Recoupling Adjustment Subtotal	$0.0024	$0.0021	$0.0012	M / B
P	**Decoupled Non-Fuel Charge Adjustment**	**($0.0005)**	**($0.0003)**	**$0.0003**	F + N
Q	Decoupled Non-Fuel Effective Charge (Marginal Block)	$0.0607	$0.0502	$0.0192	E + Q

This table shows the calculations that would be made periodically to determine the adjustment to be added (or deducted) to energy charges to decouple utility revenues from sales volume. Two discrete statistics would be required periodically for each decoupled rate class: actual period sales volume and actual period index of number of customers.

The table is configured showing annual periodic adjustment using test year sales volumes and annual period hypothetical actual sales volumes. If the decoupling mechanism is applied monthly or quarterly the test year monthly or quarterly sales volumes for the corresponding adjustment period would be used.

Line P shows the periodic adjustment that would be applied to the energy charge. The application of this adjustment to the energy charge would be identical to (and transparent to) the method used to apply the ECAC adjustment.

Line Q is illustrative and shows the resulting effective non-fuel energy charge for the marginal block. Since the adjustment shown in line P would be applied to the energy charge generally the integrity of the block structure would be preserved (similar to application of the ECAC).

Comparison of Resulting Energy Charge Revenues — Method #1

Hawaiian Electric Company - Fixed Margin Based on Marginal Energy Costs

Source data are from RMI/HECO-IR-20: revised HECO filings in Docket No. 04-0113 (Revenue at Proposed Rates)

Customer Class =>	**R/E**	**G**	**J**
Assumptions:			
Ratio of Actual Sales to Test Year Sales	**1.05**	**1.05**	**1.05**
Ratio of Actual Customers to Test Year Customers	**1.03**	**1.03**	**1.03**
Test Year Revenue Using Existing Charges			
Fuel Charge Revenues	$189,183	$33,146	$176,164
Non-Fuel Charge Revenues	$184,213	$28,242	$87,426
Total Energy Charge Revenues	$373,396	$61,388	$263,590
Production Costs	$189,183	$33,146	$176,164
Net Revenue (For Fixed Costs)	$184,213	$28,242	$87,426
Test Year Revenue Using Decoupled Charges			
Fuel Charge Revenues	$241,508	$42,318	$225,657
Non-Fuel Charge Revenues	$131,888	$19,070	$37,933
Decoupling Energy Charge Adjustment Revenues	$0	$0	$0
Total Energy Charge Revenues	$373,396	$61,388	$263,590
Production Costs	$189,183	$33,146	$176,164
Net Revenue (For Fixed Costs)	$184,213	$28,242	$87,426
Actual Revenue Using Traditional Tariff Design			
Fuel Charge Revenues	$198,642	$34,803	$184,972
Non-Fuel Charge Revenues	$193,424	$29,654	$91,797
Total Energy Charge Revenues	$392,066	$64,457	$276,770
Production Costs	$201,258	$35,262	$187,447
Net Revenue (For Fixed Costs)	**$190,807**	**$29,196**	**$89,323**
Actual Revenue Using Decoupled Charges			
Fuel Charge Revenues	$253,584	$44,434	$236,940
Non-Fuel Charge Revenues	$138,482	$20,024	$39,829
Decoupling Energy Charge Adjustment Revenues	-$1,068	-$106	$726
Total Energy Charge Revenues	$390,998	$64,351	$277,496
Production Costs	$201,258	$35,262	$187,447
Net Revenue (For Fixed Costs)	**$189,739**	**$29,089**	**$90,049**
Check			
Test Year Non-Fuel Revenues	$184,213	$28,242	$87,426
Index of Customers Growth Factor	1.03	1.03	1.03
Test Year Non-Fuel Revs. Times Customer Factor	**$189,739**	**$29,089**	**$90,049**

Comparison of Resulting Energy Charge Revenues — Method #1

Hawaiian Electric Company - Fixed Margin Based on Marginal Energy Costs

Source data are from RMI/HECO-IR-20: revised HECO filings in Docket No. 04-0113 (Revenue at Proposed Rates)

Customer Class =>	**R/E**	**R/E**	**R/E**	**R/E**	**R/E**
Assumptions:					
Ratio of Actual Sales to Test Year Sales	**1**	**1.05**	**1.05**	**1**	**1.1**
Ratio of Actual Customers to Test Year Customers	**1**	**1.05**	**1.03**	**1.03**	**1.03**
Test Year Revenue Using Existing Charges					
Fuel Charge Revenues	$189,183	$189,183	$189,183	$189,183	$189,183
Non-Fuel Charge Revenues	$184,213	$184,213	$184,213	$184,213	$184,213
Total Energy Charge Revenues	**$373,396**	$373,396	$373,396	$373,396	$373,396
Production Costs	$189,183	$189,183	$189,183	$189,183	$189,183
Net Revenue (For Fixed Costs)	**$184,213**	$184,213	$184,213	$184,213	$184,213
Test Year Revenue Using Decoupled Charges					
Fuel Charge Revenues	$241,508	$241,508	$241,508	$241,508	$241,508
Non-Fuel Charge Revenues	$131,888	$131,888	$131,888	$131,888	$131,888
Decoupling Energy Charge Adjustment Revenues	$0	$0	$0	$0	$0
Total Energy Charge Revenues	**$373,396**	$373,396	$373,396	$373,396	$373,396
Production Costs	$189,183	$189,183	$189,183	$189,183	$189,183
Net Revenue (For Fixed Costs)	**$184,213**	$184,213	$184,213	$184,213	$184,213
Actual Revenue Using Traditional Tariff Design					
Fuel Charge Revenues	$189,183	$198,642	$198,642	$189,183	$208,101
Non-Fuel Charge Revenues	$184,213	$193,424	$193,424	$184,213	$202,634
Total Energy Charge Revenues	**$373,396**	$392,066	$392,066	$373,396	$410,736
Production Costs	$189,183	$201,258	$201,258	$189,183	$213,334
Net Revenue (For Fixed Costs)	**$184,213**	**$190,807**	**$190,807**	**$184,213**	**$197,402**
Actual Revenue Using Decoupled Charges					
Fuel Charge Revenues	$241,508	$253,584	$253,584	$241,508	$265,659
Non-Fuel Charge Revenues	$131,888	$138,482	$138,482	$131,888	$145,077
Decoupling Energy Charge Adjustment Revenues	**$0**	$2,616	-$1,068	$5,526	-$7,662
Total Energy Charge Revenues	**$373,396**	$394,682	$390,998	$378,922	$403,073
Production Costs	$189,183	$201,258	$201,258	$189,183	$213,334
Net Revenue (For Fixed Costs)	**$184,213**	**$193,424**	**$189,739**	**$189,739**	**$189,739**
Check					
Test Year Non-Fuel Revenues	$184,213	$184,213	$184,213	$184,213	$184,213
Index of Customers Growth Factor	1	1.05	1.03	1.03	1.03
Test Year Non-Fuel Revs. Times Customer Factor	**$184,213**	**$193,424**	**$189,739**	**$189,739**	**$189,739**

April 2006/February 2004 Sales and Peak Forecast escalation; 2006 HECO Fuel Price Forecast

ATTACHMENT 1

DSM Avoided Cost 20 year DSM

	Production Revenue Requirements							Energy Requirements					
	with EE DSM - 20 yr			without EE DSM									
	Total Production Rev. Req. ($000) (1)	Fixed O&M Rev. Req. ($000) (2)	Fuel, Var O&M and Purchased Power ($000) (3)	Total Production Rev. Req. ($000) (4)	Fixed O&M Rev. Req. ($000) (5)	Fuel, Var O&M and Purchased Power ($000) (6)	Avoided Production Costs ($000) (7)	with DSM (GWh) (8)	w/o DSM (GWh) (9)	Avoided Energy (GWh) (10)	Avoided Energy Costs ($/MWh) (11)	PV Factor	PV cost using levelized rate dependent on DSM energy
2006	1,004,096	46,930	957,166	1,009,341	48,613	960,728	3,245	8,232	8,260	28	117.40	1.0000	(188.51)
2007	999,342	47,864	951,479	1,012,546	51,570	960,976	8,654	8,360	8,435	75	114.77	0.9210	(473.59)
2008	993,711	48,816	944,895	1,013,444	54,248	959,195	13,030	8,481	8,600	119	109.45	0.8482	(669.67)
2009	989,493	51,638	937,854	1,016,773	58,752	958,021	16,376	8,584	8,745	161	114.46	0.7812	(855.16)
2010	974,877	52,695	922,182	998,214	52,695	945,519	21,263	8,663	8,864	201	105.92	0.7195	(964.96)
2011	996,591	54,256	942,335	1,023,782	54,256	969,526	24,775	8,724	8,955	230	107.54	0.6626	(1,041.12)
2012	1,024,442	55,343	969,099	1,056,479	55,343	1,001,135	29,190	8,782	9,044	262	111.43	0.6103	(1,090.27)
2013	1,046,787	62,537	984,250	1,082,898	62,537	1,020,361	32,903	8,842	9,138	296	111.05	0.5621	(1,135.72)
2014	1,074,156	64,715	1,009,440	1,116,375	64,715	1,051,659	38,468	8,903	9,233	330	116.59	0.5178	(1,164.79)
2015	1,102,544	65,682	1,036,861	1,054,230	77,324	976,907	(54,628)	8,964	9,329	365	(149.57)	0.4767	(1,167.44)
2016	1,140,927	67,365	1,073,563	1,090,913	79,298	1,011,615	(56,444)	9,009	9,406	397	(142.09)	0.4391	(1,169.53)
2017	1,177,894	69,515	1,108,378	1,130,770	81,774	1,048,995	(54,107)	9,059	9,483	425	(127.40)	0.4044	(1,171.26)
2018	1,235,526	72,480	1,163,046	1,167,039	66,074	1,101,965	(55,654)	9,111	9,561	450	(123.54)	0.3724	(1,144.16)
2019	1,271,313	73,034	1,198,279	1,223,400	85,971	1,137,429	(55,444)	9,165	9,640	475	(116.75)	0.3430	(1,110.88)
2020	1,319,357	75,365	1,243,991	1,271,280	88,656	1,182,624	(55,915)	9,240	9,740	499	(111.99)	0.3159	(1,075.70)
2021	1,372,108	77,037	1,295,070	1,325,194	90,691	1,234,503	(55,186)	9,296	9,811	515	(107.12)	0.2909	(1,022.19)
2022	1,432,624	79,180	1,353,444	1,379,720	93,207	1,286,514	(60,983)	9,346	9,867	521	(117.06)	0.2680	(951.97)
2023	1,482,055	81,524	1,400,531	1,428,177	95,908	1,332,269	(62,197)	9,403	9,924	521	(119.32)	0.2468	(877.29)
2024	1,400,489	97,979	1,302,510	1,484,969	97,979	1,388,990	76,974	9,460	9,982	522	147.58	0.2273	(808.48)
2025	1,454,022	100,520	1,353,502	1,542,648	100,520	1,442,127	80,751	9,518	10,039	522	154.72	0.2093	(745.06)

Total (06-25) (162,930)
NPV (06$) ($18,907)

(18,906.73)
Levelized (06-25) (6.82) $/MWH
or
(0.68) ¢/KWH

General Notes:

Load forecast Apr 2006 (short). Sales/peaks beyond 2010 were derived using % increase from Feb 2004 Long Term Fcst
2006 HECO fuel price forecast
EE DSM based on .lfa files from Energy Services dated 3/22/06 and 3/23/06
LM based on the LFAs received on 3/22/06 and 3/28/06
CHP impacts assumes market size equivalent to no utility participation scenario (LFA received 12/14/05)
Assumes that HECO units and the IPP units do not retire
Assumed KPLP at 208 MW
2006 AOS EFORs reduced to 4-yr avg after 2nd CT
PS O&M 6 yr maint (2006 AOS); GPD LT maint
PV factor based on after-tax Cost of capital 8.579% per 12/21/04 email from FAD

Notes:

1. GAF Utility Costs (fixed & variable O&M, fuel, emissions and purchase power expenses) from PRV System Cost Report for WDSM06AR4.sav w/ 20-year EE DSM in 2006
2. Fixed O&M Costs from GAF System Report for WDSM06AR4.sav
3. Column (1) minus column (2)
4. GAF Utility Costs from PRV System Cost Report for NDSM06AR7.sav
5. Fixed O&M Costs from GAF System Report for NDSM06AR7.sav.
6. Column (4) minus column (5)
7. Column (6) minus column (3) with the 9.751% revenue tax removed
8. Energy Required from GAF System Report (including losses) WDSM06AR4.sav
9. Energy Required from GAF System Report (including losses) NDSM06AR7.sav.
10. Column (9) minus column (8)
11. Column (7) divided by column (10)

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April 2006/February 2004 Sales and Peak Forecast escalation; 2006 HECO Fuel Price Forecast
ATTACHMENT 2
DSM Avoided Cost 20 year DSM

	Revenue Requirements						Coincident Peak Demand					
	with DSM ($000) (12)	w/o DSM ($000) (13)	Net Avoided Revenue Requirements ($000) (14)	DSM Revenue Requirements ($000) (15)	Avoided Revenue Requirements ($000) (16)	Avoided Capital and Fixed O&M Costs ($000) (17)	Peak with EE DSM (MW) (18)	Peak w/o EE DSM (MW) (19)	EE DSM Peak Reduction (MW) (20)	Avoided Capital and Fixed O&M Costs ($/kW-yr) (21)	PV Factor	PV cost using levelized rate dependent on DSM peak impacts
2006	1,027,308	1,015,272	(12,036)	17,281	5,245	1,533	1,311.2	1,319.2	7.9	193	1.0000	5,829.77
2007	1,024,770	1,020,302	(4,468)	17,672	13,204	3,377	1,329.5	1,347.0	17.4	194	0.9210	11,379.24
2008	1,018,958	1,021,199	2,241	17,492	19,732	4,949	1,339.7	1,365.2	25.5	194	0.8482	15,332.52
2009	1,062,971	1,072,266	9,294	17,986	27,281	6,482	1,357.4	1,390.8	33.4	194	0.7812	18,488.42
2010	1,060,076	1,065,016	4,940	18,397	23,337	-	1,368.2	1,409.2	41.0	-	0.7195	20,934.69
2011	1,078,926	1,087,129	8,204	18,987	27,191	-	1,377.3	1,424.7	47.4	-	0.6626	22,286.96
2012	1,104,427	1,116,878	12,451	19,585	32,036	-	1,387.3	1,440.5	53.1	-	0.6103	22,981.81
2013	1,148,930	1,164,839	15,910	20,202	36,111	-	1,396.9	1,456.3	59.4	-	0.5621	23,683.64
2014	1,179,329	1,200,710	21,381	20,838	42,219	-	1,406.3	1,472.4	66.0	-	0.5176	24,234.46
2015	1,205,433	1,254,812	49,379	21,495	70,875	119,206	1,415.9	1,488.6	72.7	1,639	0.4767	24,587.85
2016	1,240,967	1,314,446	73,479	22,174	95,653	143,599	1,422.1	1,500.8	78.7	1,825	0.4391	24,502.78
2017	1,274,692	1,345,108	70,416	22,874	93,290	139,109	1,428.5	1,512.9	84.5	1,647	0.4044	24,220.89
2018	1,329,258	1,392,493	63,234	23,598	86,832	134,771	1,436.2	1,525.2	89.1	1,513	0.3724	23,518.95
2019	1,362,033	1,420,130	58,097	24,344	82,442	130,561	1,444.1	1,537.6	93.5	1,397	0.3430	22,728.84
2020	1,409,066	1,461,427	52,361	25,115	77,476	126,508	1,456.6	1,554.4	97.9	1,293	0.3159	21,918.13
2021	1,459,920	1,508,015	48,095	25,859	73,954	122,569	1,465.2	1,564.7	99.5	1,231	0.2909	20,533.45
2022	1,518,028	1,554,795	36,767	26,626	63,393	118,744	1,474.5	1,574.2	99.7	1,191	0.2680	18,938.75
2023	1,565,256	1,595,751	30,495	27,418	57,913	114,984	1,484.2	1,583.9	99.7	1,153	0.2468	17,445.91
2024	1,637,378	1,645,394	8,017	28,234	36,251	(43,944)	1,493.8	1,593.5	99.7	(441)	0.2273	16,072.36
2025	1,726,100	1,698,398	(27,702)	29,077	1,376	(79,499)	1,503.6	1,603.4	99.8	(797)	0.2093	14,807.00
				$445,254								
				Total (06-25)	965,810	1,042,931						394,204
				NPV (06$)	$411,893	$394,204					Levelized (06-25)	709 $/kw-yr

General Notes:

Load forecast Apr 2006 (short). Sales/peaks beyond 2010 were derived using % Increase from Feb 2004 Long Term Fcst
2006 HECO fuel price forecast
EE DSM based on .lfa files from Energy Services dated 3/22/06 and 3/23/06
LM based on the LFAs received on 3/22/06 and 3/28/06
CHP impacts assumes market size equivalent to no utility participation scenario (LFA received 12/14/05)
Assumes that HECO units and the IPP units do not retire
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2006 AOS EFORs reduced to 4-yr avg after 2nd CT
PS O&M 5 yr maint (2006 AOS); GPD LT maint
PV factor based on after-tax Cost of capital 8.579% per 12/21/04 email from FAD

Notes:

12 Utility Cost from PRV System Cost Report for WDSM06AR4.sav.
13 Utility Cost from PRV System Cost Report for NDSM06AR7.sav.
14 Columns (13) minus column (12)
15 Diff in DSM cost for EE DSM prog (excl adjstmts for T&D avd costs) from LFA Utility Cost from PRV System Cost Reports
16 Column (14) plus Column (15)
17 Column (16) minus column (7) with the 9.751% revenue tax removed
18 Final Peak from GAF Loads and Res Detail Report - WDSM06AR4.sav
19 Final Peak from GAF Loads and Res Detail Report - NDSM06AR7.sav
20 Column (19) minus column (18)
21 Column (17) divided by column (20)

CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing HAIKU DESIGN AND ANALYSIS RESPONSES TO THE NATIONAL REGULATORY RESEARCH INSTITUTE PAPER APPENDIX 2 QUESTIONS FOR THE PARTIES WITH ATTACHMENTS 1, 2 AND 3 upon the following entities, by first class mail or by electronic transmission as noted:

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Dated: February 19, 2009; Haiku, Hawaii

Signed: CARL FREEDMAN

Carl Freedman